Vectren Energy Delivery's Response To The Indiana Utility Regulatory Commission's April 12, 2006 Data Requests Regarding the 2005 Energy Policy Act's Suggested Standards

In response to the Indiana Utility Regulatory Commission's ("Commission") April 12, 2006 Data Request, Vectren Energy Delivery of Indiana, Inc. ("Vectren Energy") hereby submits the following responses. Vectren Energy appreciates the opportunity to respond in writing to these requests and looks forward to working with the Commission as it considers the suggestions of the 2005 Energy Policy Act.

I. Fuel Sources

1. Do the Indiana Integrated Resource Plan and Certificate of Need processes provide for a sufficient method to insure that utilities develop a plan to minimize dependence on one fuel source? Please Explain.

Response: Existing Indiana law provides for appropriate consideration of fuel diversity, including development of renewable energy sources. Before a regulated public utility can construct a generating facility it must obtain Commission approval. As the Commission considers a petition for authority to construct a generating facility, it shall evaluate various methods for providing service, including power purchases, conservation, cogeneration and renewable energy sources. Ind. Code §8-1-8.5-4. Moreover, the utility's proposed project must be found to be consistent with the Commission's Plan for expansion of generating capacity in Indiana. IC 8-1-8.5-5(b)(1). The Commission's Plan with respect to the long-range needs for expansion of generation facilities includes a

comprehensive analysis of load growth, reserves, the "optimal extent, size, mix, and general location" of new plants, and the comparative costs of the various means of meeting future electric requirements. IC 8-1-8.5-3. Thus, apart from reviewing every proposed generation project in terms of considering other available options to serve customers, the Commission on an ongoing basis, analyzes the mix of fuel sources used to serve customers. This review is facilitated by the Integrated Resource Plans filed by the utilities. See 170 IAC 4-7-2.

A key component of each utility's IRP is the selection of a "mix of resources" used to serve customers. 170 IAC 4-7-8. As part of the selection process, the utility must demonstrate that it utilizes, to the extent practical, renewable resources. As a result, the IRP establishes a planning process where fuel mix, including renewables, are considered and modeled as the utility creates its resource plan.

In Indiana, a utility is eligible to obtain financial incentives when it develops renewable energy resources. Ind. Code §8-1-8.8-11 puts clean coal projects and renewable energy projects on equal footing by making both eligible for timely cost recovery, enhanced returns on investment and other incentives.

2. How could the IURC best ensure that the electric energy sold to consumers is generated using a diverse range of fuels and technologies, including renewable technologies?

Response: The legislature has provided the Commission with the tools summarized above to develop plans for a proper fuel mix and use of renewables,

and has provided incentives to utilities to use renewables as a resource. The IURC can make it clear that use of a portfolio of resources that includes a mix of fuel sources is consistent with making efforts to provide supply at the lowest cost reasonably possible.

3. Is the requirement of IC-8-1-2-42(d)(1) compatible with a requirement to ensure the electric energy a utility sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies? Would summary FAC proceedings provide for timely review if such a requirement were implemented? Please explain.

Response: IC 8-1-2-42 (d)(1) should be interpreted in a manner that recognizes that diversity of fuel may be prudent in mitigating potential volatility in the cost of a specific fuel at any given time, and therefore provides customers with energy at the lowest cost reasonably possible. The Commission has already interpreted IC 8-1-2-42(g)(3)(A) in a manner that allows gas utilities to engage in hedging strategies to mitigate price volatility even though, in a given time period, they may procure supply at a cost above current market prices. The FAC cost reasonableness standard should encompass evaluation of reliability and price volatility – if the standard is so applied, then fuel diversity can be appropriately accommodated. In accommodating the portfolio approach, the Commission should allow each utility the flexibility to create the resource mix that fits its size, location, and existing resource profile. An arbitrary requirement for integration of a specific type of fuel or generating method that ignores transmission congestion, lack of renewable resources in its geographic area, current nature of a utility's investment in resources, and its flexibility given its load size, would be potentially

detrimental to customers from a cost perspective, and would negate the planning efforts and expertise that exist today. The IRP and certificate of necessity processes provide the opportunity for the Commission to engage in processes with each utility to create an appropriate fuel mix for that utility. Those processes are superior from a planning perspective compared to use of a summary FAC proceeding as a planning mechanism. Further, the IRP and certificate processes allow the Commission to make determinations regarding the balance of cost and fuel diversity considerations in light of the comprehensive analytic review the Commission engages in to create its Plan for meeting customer demand in Indiana.

4. Does today's energy market environment provide sufficient incentive for utilities to diversify their fuel sources? Please explain.

Response: The development of the Day Two energy market provides incentives to invest in infrastructure that will improve the ability to move energy across the transmission system. To the extent this promotes the ability to invest in renewable energy resources knowing that the generated energy will be moved to buyers in other areas of the country, Day Two does support fuel diversity. From a buyer perspective, sources of green power may be more accessible via an improved grid. Day Two does not change the pre-Day Two desire of generators to have low cost energy available to sell into the marketplace.

II. Fossil Fuel Generation Efficiency

1. What, if any, specific plans has your utility put in place to drive increased fossil fuel generation efficiency? How do these plans differ from what was done in the past? How do you expect these plans to change over the next ten years?

Response: Vectren Energy consistently evaluates methods to improve the efficiency and reliability of the generation fleet. The company continues to develop asset management techniques to insure that the system receives the benefits of efficiency and reliability enhancements. The company has not changed its approach to efficiency for the future. However, our past experience with and understanding of the US EPA's interpretation of the New Source Review (NSR) rules has proven to provide significant risk to utilities that implement efficiency improvements. As a company that has been sued by the EPA related to application of the NSR rules, extensive evaluation is performed prior making a decision to invest in a capital project which would improve efficiency.

System wide efficiency has been somewhat impaired by the addition of the necessary equipment to comply with the latest environmental regulations. Recently, we have focused on efficiency improvements which are designed to offset the losses associated with installation of environment enhancement devices.

The long term approach to efficiency enhancements will be heavily impacted by the environmental regulatory changes that are implemented during the next ten year period. EPA regulation will also have a very significant impact on the efficiency of any new generation that is installed within the next decade. Our objective is to balance the energy efficiency of new generation with the appropriate level of emission controls.

During the past decade the Vectren Energy generation fleet has received numerous efficiency improvements. Examples of these improvements are installation of improved design turbine blades, installation of higher efficiency feedwater heaters, replacement of insulation with higher R-factor insulation, installation of variable frequency drive, use of higher efficiency motors and frequent routine maintenance on all types of plant equipment.

2. Does today's energy market environment provide sufficient incentive for utilities to increase the efficiency of its fossil fuel generation? Please explain.

Response: The MISO based energy market provides rewards for generators that operate units which are efficient enough to be selected to support the market requirements. The most efficient economic dispatch is achieved when the units are operated at their rated capacity. The more efficient the unit, the larger the gap between cost and the market clearing price. Therefore, any reduction in coal consumption per mw is rewarded as increased margin to that unit.

3. Provide the historical annual operating efficiencies for the past 10 years for each of your fossil fuel generation plants and a similar cumulative value for your utility.

Response: The chart see forth below provides the requested data. The increase in heat rate of the steam system which is apparent starting in 2003 is a direct result of the addition of SCRs and fabric filter to comply with environmental rules. These environmental controls always increase the auxiliary load consumption without improving the generation of the unit.

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Steam System										
A.B. Brown Unit 1	31.8%	32.1%	32.2%	31.8%	32.4%	33.0%	32.6%	32.1%	32.1%	32.0%
A.B. Brown Unit 2	32.8%	32.3%	32.1%	33.0%	32.9%	32.9%	32.6%	31.6%	32.3%	32.3%
F.B. Culley Unit 1	28.4%	27.9%	27.9%	29.4%	28.9%	28.9%	28.2%	28.8%	29.1%	28.7%
F.B. Culley Unit 2	28.4%	27.6%	27.4%	28.1%	27.9%	27.9%	28.9%	28.1%	29.0%	28.8%
F.B. Culley Unit 3	32.2%	32.7%	34.1%	34.2%	33.5%	32.9%	33.3%	33.4%	33.5%	33.0%
Warrick Unit 4	33.3%	32.7%	32.4%	33.0%	33.1%	32.8%	32.4%	32.9%	32.5%	31.8%
Steam System	**32.0%**	**31.8%**	**32.1%**	**32.4%**	**32.4%**	**32.3%**	**32.4%**	**32.0%**	**32.2%**	**31.9%**
Peaking System										
A.B. Brown Unit 3	28.3%	27.3%	26.8%	25.6%	25.0%	24.0%	21.8%	26.7%	27.4%	24.6%
A.B. Brown Unit 4	28.3%	27.3%	26.8%	25.6%	25.0%	24.0%	21.8%	26.7%	27.4%	24.6%
Broadway Unit 1	19.3%	18.7%	19.0%	18.3%	17.0%	16.7%	20.5%	18.7%	19.9%	16.4%
Broadway Unit 2	24.8%	24.9%	25.3%	24.3%	22.5%	22.6%	22.6%	20.5%	24.3%	24.5%
Northeast Unit 1	17.1%	13.4%	17.0%	17.4%	14.6%	17.0%	14.2%	16.3%	17.2%	14.8%
Northeast Unit 2	17.1%	9.0%	18.2%	14.9%	16.0%	17.3%		18.1%	17.8%	15.0%
Peaking System	**25.5%**	**24.4%**	**24.0%**	**22.8%**	**21.9%**	**22.5%**	**23.6%**	**25.1%**	**26.6%**	**24.5%**
Total Utility	**32.0%**	**31.7%**	**31.9%**	**32.2%**	**32.2%**	**32.2%**	**32.2%**	**31.9%**	**32.1%**	**31.8%**

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Steam System										
A.B. Brown Unit 1	10,728	10,643	10,594	10,743	10,531	10,343	10,456	10,633	10,630	10,677
A.B. Brown Unit 2	10,394	10,573	10,629	10,330	10,382	10,383	10,474	10,817	10,562	10,558
F.B. Culley Unit 1	12,006	12,235	12,240	11,602	11,802	11,805	12,111	11,861	11,724	11,892
F.B. Culley Unit 2	12,010	12,358	12,462	12,137	12,227	12,223	11,809	12,158	11,751	11,861
F.B. Culley Unit 3	10,590	10,439	10,015	9,976	10,179	10,370	10,244	10,233	10,188	10,345
Warrick Unit 4	10,245	10,429	10,520	10,351	10,302	10,411	10,530	10,363	10,495	10,721
Steam System	**10,652**	**10,730**	**10,630**	**10,531**	**10,546**	**10,561**	**10,549**	**10,680**	**10,606**	**10,697**
Peaking System										
A.B. Brown Unit 3	12,057	12,502	12,750	13,325	13,654	14,220	15,688	12,770	12,467	13,883
A.B. Brown Unit 4	12,057	12,502	12,750	13,325	13,654	14,220	15,688	12,770	12,467	13,883
Broadway Unit 1	17,674	18,246	17,935	18,638	20,125	20,391	16,686	18,264	17,139	20,867
Broadway Unit 2	13,759	13,692	13,512	14,051	15,165	15,120	15,115	16,678	14,059	13,913
Northeast Unit 1	19,937	25,378	20,126	19,612	23,382	20,063	24,050	20,939	19,800	23,003
Northeast Unit 2	19,904	38,091	18,745	22,888	21,373	19,754		18,860	19,132	22,773
Peaking System	**13,364**	**13,991**	**14,246**	**14,951**	**15,588**	**15,157**	**14,452**	**13,619**	**12,829**	**13,954**
Total Utility	**10,663**	**10,751**	**10,685**	**10,586**	**10,595**	**10,594**	**10,615**	**10,701**	**10,622**	**10,728**

III. Smart Metering

1. Please describe the present status of time-based metering and communications within your customer base. Include detail by customer class (e.g. residential, commercial, industrial) relating to tariff offerings, smart meters deployed, means of communicating collected data with participating customers, and capital invested in infrastructure.

Response: Presently, time based metering is only available to customers taking service at primary or transmission voltage and having a Billing Demand of 300 kVa or greater. The Billing Demand for the current month is the average load in kilovolt-amperes during the 15-minute period of maximum use in such month, but not less than 60% of the highest Billing Demand during the preceding 12 months and in no event less than 300 kVa. Customers' meters are manually read and the interval data is maintained in the Itron MV-90 system. There are currently 102 customers on Rate Tariff LP and 2 customers on Rate Tariff HLF. The endpoint equipment cost for the MV-90 system is approximately $750 per meter and $1,122 per transformer.

Vectren has offered a Direct Load Control (DLC) Program to residential and commercial customers since April 1992. The objective of the program is to reduce summer coincident peak by temporarily cycling central air conditioners and heat pumps and by shedding connected water heater loads. The DLC (Summer Cycler) program is a voluntary program where customers allow a load management switch to be installed at no charge to the customer on their central air conditioning and water heating equipment. Based upon a radio communication signal the appliances can be cycled off for range of cycling strategies (33%, 42% and 50% during a half-

hour (10, 12.5 or 15 minutes per half hour) during times of peak demand between the months of May through September. Participating customers receive a bill credit during these months. Vectren currently has 41,104 residential DLC switches installed providing a range of approximately 27,099 kW to 39612 kW of peak load reduction depending upon the cycling strategy. There are 2681 active commercial switches saving approximately 3734 kW of peak load reduction capability. Greater load reductions could be achieved in emergency situations.

2. Describe the methods utilized presently or historically to communicate tariff/program opportunities to customers. Do you have plans to enhance marketing of these opportunities? Please explain.

Response: For residential and small commercial customers, the customer communications take place via bill inserts, bill messages, direct mail campaigns, and Vectren's web site.

For large commercial and industrial customers, the Account Managers proactively meet with customers during tariff changes and explain new implementations. We also conduct yearly customer meetings to discuss Marketing efforts as well as the company outlook as it relates to the natural gas and electric business. As customers request information, the Account Managers set individual meetings to discuss pertinent tariff information.

Vectren does not currently have plans to change these communication efforts but enhancements will be considered as new programs are developed.

3. Detail any cost/benefit studies conducted for your service area regarding time-based metering communication deployment and tariffs. Detail should at a minimum include cost and demand response assumptions.

   Response: Vectren has not conducted any specific/detailed cost benefit studies concerning the use of time based metering communication deployment or tariffs. Vectren has evaluated automated/advanced metering systems from three different vendors. The systems offer various levels of time-based metering capabilities as well as other operational benefits. Vectren has used industry information to estimate the pay-back period for these systems to be between 8 and 10 years.

4. Detail the response to any customer surveys you may have conducted in your service area regarding time-based metering and rates. If no surveys have been conducted, what customer input method does your utility employ to evaluate customer demand for time-based metering and rate offerings?

Response: Vectren has not conducted any customer surveys on this subject.

5. What, if any, regulatory barriers exist which limit the expansion of time-based metering and rates?

Response: The investment in technology infrastructure to implement time-based metering and rates would be significant and the utility would have to have a way to make timely recovery of investments in such technology.

6. Can time-of-use rates be effectively implemented without the use of smart metering? Please describe any new or expansion of existing time-of-use rates your utility plans to implement in the next 24 months.

Response: Vectren believes that time-of-use rates cannot be effectively implemented without the use of meters that are capable of time-stamping usage and a meter data management system to maintain this data. A robust communication network is also required in order to communicate metering information as well as tariff/pricing information to customers.

Vectren currently has no plans to offer any new time-of-use tariffs in the next 24 months.